CHAPTER 2
LOAD BALANCE

The load balance, or demand/supply equations, which ensures that user specified demands are met for each of the hours in the six representative day types in the model – summer/winter peak, off-peak, and average days – are described in this chapter (see also Appendices I, II and VII).

2.1 The Demand for Electricity

The model is driven by the "typical hour/day/season/year" chronological demand approach taken by many of the latest commercial models, rather than the load duration curve methodology used in earlier approaches. Appendices I and II give all the input files necessary to create the demand drivers for the model. Demands and supplies are for the utilities in SAPP, rather than for the SAPP countries. Thus, municipalities or others in the SAPP countries which generate and use their own electricity are not considered in calculating either the forecast demand, or the power available to meet such demands.

The model is set up to model demand in a user specified number of representative periods (up to 10) in the future, by selecting the parameter *Yper(ty)* (found in Appendix II, Section 2) starting in a user specified year – 2000 is the default value. Base year demand data are entered into the model using the SAPP specified format as of February 2000;

- enter weekly peak load (in per unit values) for the base year in Table *Uweek( )* found in Appendix I, Section _____ (52 values)
- enter hourly load data for a representative week, in per unit values in Table *Uhour( )* found in Appendix I, Section ____ (24 x 7 values).
- enter peak hour, in MW for the base year, in Table *Upeak*
- enter total MWh in the base year, entered into parameter *DMWh(z)*.

Then model then automatically converts this data into Table *Base(ts,td,th,z)* (Appendix VIII, Section ___) which gives the base year demand data for the 36 representative hourly demands the model uses to drive the model, as explained below.

Table *Yper(ty)* sets the number of periods in the planning horizon. If the user wishes to consider, say a 5 period horizon, then the user enters 1 in the table for per1 to per5 and 0 thereafter.

The model also allows the user to decide how many years each period will represent - every year, every other year, every third year, etc. by selecting the value for scalar *n* in the model. (See Appendix I) The model automatically adjusts the yearly growth rates and the cost function to insure the model fully adjusts to the period and years/period selection made by the user, allowing a wide range of planning horizons.

In all cases, no capacity expansion is allowed in the initial year; those construction projects SAPP indicated would be completed by the initial year are included as installed capacity. Thus, the first year's optimization involves only dispatch of existing capacity against the first year's demand.

Yearly demand growth rates which differ by time period *n* and by country *z* can be specified by the user (parameter *dgrowth1(z), dgrowth2(z), dgrowth3(z),* etc…, in Appendix II, Sections 2, 3 and 4). The program automatically converts the yearly growth rates entered in the tables *dgrowth1(z)* into *dgr(z,ty),* the proper growth rates for the periods of varying length in the model as indicated in Section 1 of Appendix VII.

In creating the base year demand drivers for the model from the SAPP input data format, the model first selects within each year -- two seasons -- summer and winter. The summer period contains nine months (273 days), while the winter contains three months (91 days). Within each season, three days -- a peak day, an off-peak day, and an average day -- are modeled.

Within the summer season, there are 39 peak days, 78 off-peak days, and 156 average days. Within the winter season, there are 13 peak, 26 off-peak, and 52 average days.

Within each day type, six hours are modeled; one off-peak hour, taken to be hour 9, three peak hours, hours 19, 20 and 21, two average hours, one average night hour

(avnt), representing 8 night hours; and one average day hour (avdy), representing 12 average day hours, peaks excluded. Users can select other weights by entering desired weights in Table *Mtod(th)* found in Section 1 of Appendix I, but should select such weights to insure the hours total to 24.

All this comes together in creating the demand driver for the model, parameter *Dyr(ty,ts,td,th,z)* (Section 2 of Appendix VII), which is country *z*'s MW demand in year *ty* in season *ts* (*ts* = winter, summer) in day *td* (*td* = peak, off-peak, average) in hour *th* (*th* = hr9, avnt, hr19, hr20, hr21, and avdy): Combining the yearly growth assumptions with the base year day type demand data found in Table *Base(ts,td,th,z)*, we have;

$$Dyr(ty,ts,td,th,z) = Base(ts,td,th,z)dgr(z,ty)$$

The GAMS notation is shown in Appendix VII, Section 2.

If the total GWh in the base year, as calculated by this method, does not equal the total GWh as reported in parameter *DMWh(z)*, the program scales up or down the data in *Base(ts,td,th,z)* by multiplying it by a correction factor *Correction(z)* which equates the base year MWh as calculated by the program to that reported by users in *Parameter(z)*.

Next, the impact on these demands of domestic distribution loss and demand-side management must be considered.

Table *DLC(z)* in Appendix II, Section 5 -- the domestic loss coefficient in the model -- is applied to the demand value to allow for electricity loss within each SAPP region; it converts demand at the customer meter into demand at the generating station. If users enter sent out demand at the generating stations into the base year demand tables, *DLC(z)* should be set to 1.0.

The load management parameter -- (*LM(z,th)* in Appendix VI, Section 12) -- allows SAPP member specified *LM* options to fractionally adjust up or down the load shapes of the representative days in the model. It should be emphasized that the model in its current form does not compete *LM* against normal supply side options to obtain the least cost mix of *LM* and capacity expansion. It simply allows various *LM* options with known costs to be entered into the model to see "off-line" if they are cost effective when

compared to supply alternatives. It is planned to add *LM* to the optimization formulation at a later date.

Combining the period growth assumptions with the *DLC* and *LM* data allows the specification of the right-hand side of the load balance equation, which specifies, for each hour in each day in each season in each year, the demand at the generating station that must be met inclusive of the effect of distribution line loss and *LM* programs;

$$[Dyr(ty,ts,td,th,z)\text{-}LM(z,th)][DLC(z)]$$

The choice of the number of periods in the planning horizon, *Yper(ty)* governs the demand side of the equation, in that the demand side is multiplied by *Yper(ty)*;

$$Yper(ty)\left[Dyr(ty,ts,td,th,z)-LM(z,th)\right]\left[DLC(z)\right]$$

This is the right hand side of the load balance equation "Equation Demand" found in Appendix VII, Section 26.

Since *Yper(ty)* = 1 for all periods within the planning horizon, and 0 for all periods beyond the horizon, the model only optimizes within the planning horizon; no demands need to be met beyond the horizon.

2.2 The Supply Side

The demand in a given region can be met from a variety of energy sources: (a) existing thermal sites, (b) new thermal sites, (c) existing hydro sites, (d) new hydro sites, (e) pumped storage, (f) net imports (imports less exports), (g) paying an unserved energy cost.

Within each region, generating sites are identified which contain generating plants. For purposes of dispatch, all plants at a site are collectively dispatched. Generation variables, in MW, for the sites are:

PG(ty,ts,td,th,z,i) = generation from existing thermal site *i*

PGNT(ty,ts,td,th,z,ni) = generation from new gas turbines at site *ni*

PGNSC(ty,ts,td,th,z,ni) = generation from new small coal plants at site *ni*

PGNCC(ty,ts,td,th,z,ni) = generation from new combined cycle plants at site *ni*

PGNLC(ty,ts,td,th,z,ni) = generation from new large coal plants at site *ni*

H(ty,ts,td,th,z,ih) = generation from existing hydro site *ih*

Hnew(ty,ts,td,th,z,nh) = generation from new hydro site *nh*

PGPSO(ty,ts,td,th,z) - *PUPSO(ty,ts,td,th,z)* = net generation from old pumped hydro sites (*PGPSO* is generation supply, *PUPSO* is pump demand)

PGPSN(ty,ts,td,th,z,phn) - *PUPSN(ty,ts,td,th,z,phn)* = net generation from new pumped hydro sites (*PGPSN* is generation supply, *PUPSN* is pump demand)

Default value characteristics of new and old plants are based on data furnished by SAPP members.

Minimum and maximum run levels for new plants, *minT(z,ni)*, *maxT(z,ni)*; *minSC(z,ni)*, *maxSC(z,ni)*; *minCC(z,ni)*, *maxCC(z,ni)*; *minLC(z,ni)*, *maxLC(z,ni)*; *minHN(z,nh)*, *maxHN(z,ni)*; and old plants *PGmin(z,i)*, *PGmax(z,i)*, *minH(z,ih)*, and *maxH(z,ih)*, can be set by users; they are found in Section 19 of Appendix IV for thermal units, and Section 9 of Appendix V for hydro units. Both the minimum and maximum utilization levels are entered as capacity factors – that is minimum and maximum percent utilization of whatever the current capacity is for the unit in question. Note that this method does not require the unit to be built, since *x%* of zero is still zero. Users should use the *At_ _(z,ni), Bef_ _(z,ni), or Aft_ _(z,ni)* options described in Chapter 3 to force the model to build a unit at, before, or after a user specified year. The equations which insure these constraints are met are found in Section 26 of Appendix VII; names are Equation *Tmin*, Equation *SCmin*, etc.

(a) Existing Thermal Sites

Table 1.1 in Chapter 1, and Table *PGOinit(z,i)*, in Section 13 of Appendix IV, both list the year 2000 current MW capacities of the existing thermal sites in the model (including Nuclear, Koeberg, SSA). The rows in Table *PGOinit(z,i)* are the locations listed in order of the *z* index assigned - e.g., Ang (Angola) is *z*=1, Bot (Botswana) is *z*=2, etc., Zimbabwe is *z*=14. (Note Mozambique and RSA are divided into two regions -north

and south -to recognize the reality of the split supply situation in Mozambique, and the split demand situation in RSA). The site index *i* follows the column index stat i.

Power generation in period *ty*, season *ts*, day type *td*, hour *th*, at old site *i* in country *z* is given by the continuous non-negative variable *PG(ty,ts,td,th,z,i)*. Thus *PG(1,1,1,1,1,1)* is the MW contribution of Angola (*z*=1) site 1 (stat 1) during period 1 (2002) in season 1 (winter) in day type 1 (off-peak) during hour 1 (summer, peak, avnt).

(b) New Thermal Sites

Table 1.3 in Chapter 1 lists the capacities of new or recommissioned thermal plants under consideration by SAPP. The new sites have been grouped into five categories, depending on their size, fuel type, and technology:

- Simple cycle combustion turbines – (NSA and Angola) – power generation from such sites is given by the variable *PGNT(ty,ts,td,th,z,ni)* where *ni* is the site index for combustion turbines in country *z*; proposed capacities can be found in Table 1.3 listed as *T-GT*.
- Combined cycle combustion turbines (Namibia and Tanzania) – power generation from such sites is given by the variable *PGCC(ty,ts,td,th,z,ni)*; proposed capacities for these units can be found in Table 1.3 listed as *T-CC*.
- Small (< 500 MW) coal fuel plants (Botswana, NSA, and Zimbabwe) – power generation is given by *PGSC(ty,ts,td,th,z,ni)*; proposed capacities for these units can be found in Table 1.3, listed as *T-SC*.
- Large (> 500 MW) coal fuel plants (NSA only) – power generation is given by *PGLC(ty,ts,td,th,z,ni)*; proposed capacities for those units can be found in Table 1.3, listed as *T-LC*.
- Nuclear plants (in RSA only), listed as *T-NUC*.

Users can add additional projects in each of the categories for consideration by entering the necessary cost and performance data into the data tables in the thermal data section, either directly, or through the interface described in Chapter 7. Once the data are entered, the model automatically adds the proposed project to the list of projects under consideration.

The model can have a total of eight new projects per technology per country (including those listed in Table 1.3) allowing the user substantial flexibility in the specification of new thermal options for consideration.

(c) Existing Hydro Sites

Table 1.2 in Chapter 1, and Table *HOinit(z,ih)* - *z* the row (country) index, *ih* the column (site) index - in Section 4 of Appendix V, list the year 2000 current MW capacities of the existing hydro sites in the model. A complete description of the sites will be given later in the report.

MW output from the existing sites is given by the variable *H(ty,ts,td,th,z,ih).*

(d) New Hydro Sites

Table 1.3 in Chapter 1, and Table *HNinit(z,nh),* in Section 1 of Appendix V – again *z* the row (country) index, *nh* the column (new site) index list the hydro sites under consideration by SAPP members. The options, as expected, are dominated by the expansions of DRC's Grand Inga hydro site, which accounts for over two-thirds of planned hydro capacity.

MW output from the new sites is given by the variable *Hnew(ty,ts,td,th,z,nh).*

(e) Pumped Storage

At least two SAPP members (RSA and Tanzania) either have, or are planning to add, pumped storage as a means of peak-shaving/valley filling their 24-hour demand profiles. Table 1.3 contains data on the four known pumped storage projects planned by RSA. Pump storage uses electricity off-peak to pump water up to reservoirs, which are then discharged during peak periods.

The hourly (MW) amount of on-peak generating at the two existing pump storage sites in RSA will be indicated by the non-negative variable *PGPSO(ty,ts,td,th,z),* while the hourly MW amount of off-peak pumping will be indicated by the non-negative variable *PUPSO(ty,ts,td,th,z).* The power available for generation must be less than the power used to pump because of pump storage system loss, given by the parameter *PSOloss* in Section 9 of Appendix V. (Default value is 0.3.) Pumped storage facilities are assumed to operate on a 24-hour cycle - e.g. what is pumped up in a night must come

down in the same day. Thus, the sum over all hours in a day of *PGPSO(ty,ts,td,th,z)* cannot exceed the sum overall hours of *PUPSO*, less loss;

$$\sum_{th} PGPSO(ty,ts,td,th,z) \leq \sum_{th} PUPSO(ty,ts,td,th,z)(1-PSOloss)$$

The GAMS format, equation *oldpumped* is shown in Appendix VII, Section 25; the same equation type holds for new pumped sites, when constructed. There are additional constraints, described in Chapter 3, which limit the instantaneous generation rate, and the total storage volume available per day.

The GAMS equation indicates this is always an equality at an optimum solution, since it was decided not to include the possibility of longer term storage in the model.

The model enters pumped storage into the load balance equation on the supply side; hence *PGPSO(ty,ts,td,th,z)* enters with a positive sign, while *PUPSO(ty,ts,td,th,z)* enters with a negative sign; e.g.

Generation plus net imports *+PGPSO(ty,ts,td,th,z) - PUPSO(ty,ts,td,th,z)* = Demand

Pumped storage from new sites (indexed *phn*) enters into the model in a similar fashion, except the variables are *PGPSN(ty,ts,td,th,z,phn)* and *PUPSN(ty,ts,td,th,z,phn)*. Data Tables for *PSNloss(phn)* are found in Section 9 of Appendix V.

In GAMS format, equation *Newpumped* is shown in Appendix VII, Section 25.

(f) Net Imports

Figures 1.2 and 1.3 in Chapter 1, and Tables *PFOinit(z,zp)* and *PFNinit(z,zp)* in Sections 1 and 7 respectively of Appendix III list the initial MW capacities of the existing and proposed lines respectively linking the 14 nodes which make up SAPP in the model. The tables are symmetric, so that power flow capacity from country A to B is the same as B to A, even for DC lines (see below).

Transmission losses on the lines are given in tables *PFOloss(z,zp)* for existing lines, and *PFNloss(z,zp)* for new lines in Sections 3 and 5 respectively in Appendix III. Uni-directional DC lines in the model are modeled by assuming infinite loss in the counter flow direction.

Recalling that there are two types of power flows in the model – firm power flows (power flows from export country capacity held in reserve to insure power availability at all times during the period covered by the capacity commitment) and non-firm power

flows (flows from export country capacity which does not have the guaranteed continuous availability feature of firm power), one would expect the model to contain two sets of power flow variables – one firm, one non-firm. In fact, the model contains only the total of firm and non-firm power flows, since in reality, there is no way before the fact to label some flow firm, and some non-firm.

In the model, as in the real world, there is just a single decision flow variable *PF(ty,ts,td,th,zp,z)* which measures flow from country *zp* to country *z*, and a single capacity reservation decision variable, *Fmax(ty,zp,z)* which represents capacity that country *zp* reserves for possible use by country *z*. The optimization proceeds with no explicit connection between the two decision variables. They independently seek the level that is consistent with SAPP wide cost minimization - *PF(ty,ts,td,th,zp,z)* competing with imports from other countries and domestic generation to satisfy power demands in country *z*, *Fmax(ty,zp,z)* competing with domestic reserves to satisfy country *z's* reserve requirements. After the optimal values of *PF(ty,ts,td,th,zp,z)* and *Fmax(ty,zp,z)* are determined, a calculation can be made to separate *PF(ty,ts,td,th,zp,z)* into firm and non firm power by recognizing that the excess (if any) of *PF(ty,ts,td,th,zp,z)* over *Fmax(ty,zp,z)* is non firm power; the rest is firm. (See the detailed discussion of this and related points at the end of Chapter 4.)

The model does this calculation automatically, and the results are reported in the Trade.out file.

MW power flows from country *z* to *zp* on old lines are given by the variables *PF(ty,ts,td,th,z,zp)* while flows on the new lines are given by the variables *PFnew(ty,ts,td,th,z,zp)*. Using this notation, and accounting for line losses reducing the amount of power arriving at country *z*, net imports for country *z* in a given hour would be;

$$\sum_{zp}\left[\overbrace{PF\left(ty,ts,td,th,zp,z\right)\left(1-PFOloss\left(zp,z\right)\right)}^{\text{imports arriving on old lines}}-\overbrace{PF\left(ty,ts,td,th,z,zp\right)}^{\text{exports sent on old lines}}\right]+$$

$$\sum_{zp}\left[\overbrace{PFnew\left(ty,ts,td,th,zp,z\right)\left(1-PFNloss\left(zp,z\right)\right)}^{\text{imports arriving on new lines}}-\overbrace{PFnew\left(ty,ts,td,th,z,zp\right)}^{\text{exports sent on new lines}}\right]$$

Note that the assumption that line losses reduce the amount of power arriving at country *z* implies that the importer bears the line loss; alternatively, the exporter could have borne the loss, or the loss split 50/50. All this will alter only the cost/MWh, but not the real cost to SAPP of the transaction.

As in the case of generating units yearly minimum and maximum use levels for new and old lines can be set by the user by entering in Tables *minPFO(z,zp)*, *maxPFO(z,zp)*, *minPFN(z,zp)*, and *maxPFN(z,zp)* the minimum and maximum yearly power flows in MWh found in Section 7 of Appendix III; the equations are found in Section 26 of Appendix VII named *PFmin*, *PFmax*, *PFNmin*, and, *PFNmax*.

As in the case of minimum and maximum utilization levels for generating units, minimum and maximum flow levels for lines are entered as line capacity factors, expressed as a percent of the current capacity. Thus, if a user wished to bound the use of a line between 20% and 80% of its maximum yearly KWh capacity, the user would enter 20 in *minPF_ _(z,zp)* and 80 in *maxPF_ _(z,zp)*. These constraints are particularly useful when testing the impact of forced exports on the optimal solution. To prevent the model from immediately sending back forced exports during the re-optimization, the program automatically sets *maxPFO(zp,z)* to zero whenever *minPFO(z,zp)* is greater than zero, and sets *maxPFN(zp,z)* to zero whenever *minPFN(z,zp)* is greater than zero.

(g) Unserved Energy

Each region can choose not to meet hourly demand by allowing unserved energy to enter the supply side of the demand/supply balance equation. The variable *UE(ty,ts,td,th,z)* gives the MW value of the amount. The scalar *UEcost*, Section 1 of Appendix II, sets the cost/MWh of unserved energy. The nominal value is $140/MWh, but it can be set at whatever value users want to adopt.

As will be explained later, the model also allows the reserve requirements constraints to be violated by setting the variable *UM(z,ty)* – unsatisfied MW reserve requirements – to some positive level, at a cost/MW set by the user.

Finally, since it is possible that the presence of “must run” constraints may force supply (generation plus imports) to be greater than demand (consumption plus exports)

without the user recognizing the fact, a new dummy variable dumped energy, *DumpEn(ty,ts,td,th,z)* is added and the inequality converted to an equality – e.g.;

generation + imports + unmet demand = consumption + exports + dumped energy

Thus, if there is insufficient generation to meet demand, unmet demand is greater than zero; if, because of must run constraints, generation exceeds demand, then dumped energy is greater than zero. In all cases, the load balance is just that, a balance of demand and supply.

2.3 The Full System Load Balance Equation

The load balance equation - "Equation Demand" in the model - requires that for all time periods for each country *z*, the sum of MW generation from:

- existing thermal sites - *PG(ty,ts,td,th,z,i)*
- new thermal sites - *PGNT(ty,ts,td,th,z,ni)*, *PGNCC(ty,ts,td,th,z,ni)*, *PGNSC(ty,ts,td,th,z,ni)*, *PGNLC(ty,ts,td,th,z,ni)*
- net firm and non-firm imports over existing transmission lines – *PF(ty,ts,td,th,zp,z)(1-PFOloss(zp,z) - PF(ty,ts,td,th,z,zp)*
- net firm and non-firm imports over new transmission lines - *PFnew(ty,ts,td,th,zp,z)(1-PFNloss(zp,z)) - PFnew(ty,ts,td,th,z,zp)*
- existing hydro sites - *H(ty,ts,td,th,z,ih)*
- new hydro sites - *Hnew(ty,ts,td,th,z,nh)*
- old pumped storage - *PGPSO(ty,ts,td,th,z) - PUPSO(ty,ts,td,th,z)*
- new pumped storage - *PGPSN(ty,ts,td,th,z,phn) – PUPSN(ty,ts,td,th,z,phn)*

plus unserved energy

- *UE(ty,ts,td,th,z)*

must equal

- $Yper(ty) * DLC(z) * \left[Dyr(ty,ts,td,th,z) - LM(z,th) \right]$
- plus dumped energy *DumpEn(ty,ts,td,th,z)*

all this is entered into the model using GAMS notation as equation *Demand(ty,ts,td,th,z)* and found listed in Appendix VII, Section 26.